SPE-182043-MS

Incremental Oil Recovery Due to Low-Salinity Waterflooding: Pervomaiskoye Oil Field Case Study

Vadim Akhmetgareev, TatNIPIneft, Tatneft; Rais Khisamov, Tatneft

This paper was prepared for presentation at the SPE Russian Petroleum Technology Conference and Exhibition held in Moscow, Russia, 24-26 October 2016.

Abstract

The objective of the paper is to assess incremental oil production due to low-salinity waterflooding (LSW) in the Pervomaiskoye oil field operated by PJSC TATNEFT vs. conventional waterflooding by high-salinity water. In this field, low-salinity water has been injected for a relatively lengthy period enabling to assess the effects of low-salinity flooding.

The procedure was as follows. Laboratory coreflood experiments included preparation of cores, their saturation with formation water and oil, core flooding using high-salinity and low-salinity water. In both cases, oil production was recorded and fines release was analyzed. Core test results were adjusted using a special numerical fines migration model, and relative permeabilities were calculated. Then a 3D model was built and history matched using the function that allows change of relative permeability to water. After this, the model was recalculated without this function and incremental oil production due to LSW was estimated.

3D modeling showed that cumulative additional oil production due to LSW in Pervomaiskoye oil field is 4.2 million m3, incremental oil recovery is 3.5 %. The effect was prominent in wells with wellstream water cut from 20 % to 90 %.

Targeted application of LSW is recommended – in injection wells as an EOR method when wellstream water cut ranges from 20 % to 90 %, and in production wells as a water control technology.

Introduction

Low-salinity waterflooding has recently attracted much interest from oil companies worldwide, who are evaluating the method's potential to enhance oil recovery. Ever increasing number of laboratory research and field tests have shown that hopes pinned on the low-salinity water flooding are not groundless. Under low-salinity water we imply water from surface sources (rivers, lakes etc.) duly treated for injection into the formation pressure maintenance system. Under high-salinity water we mean formation or produced water.

Because of deficiency of produced water at the initial stage quite a few waterflooding projects use fresh water. The Pervomaiskoye oil field in the Republic of Tatarstan, Russia, is one of such fields. The field is partly under a huge water-storage reservoir created in 1978 on the Kama river. To prevent freshwater pollution Russian environmental laws prohibit the use of high-salinity water (HSW) for injection, so this field was flooded with low-salinity water (LSW), however the effects of LSW have never been studied before. The objective of the paper is to assess incremental oil recovery due to LSW in the Pervomaiskoye oil field vs. conventional HSW.

Physical mechanisms of low-salinity water injection in clastic reservoirs

Clastic rocks (sandstones and siltstones) very often contain clay impurities because of the presence of clay-forming materials (feldspar, plagioclase, potash feldspar etc.). Over millions of years clay particles formed under pressure and temperature, occasionally they migrated and adsorbed on the rock surface. As a result, micron-sized clay particles can be found on the rock pore surface in clastic reservoirs. Under initial conditions the sand (rock) grain surface is positively charged while clay particles are negatively charged (Fig. 1). Formation water is positively charged in contrast to negatively charged oil. This is a typical example of water-wet formations.

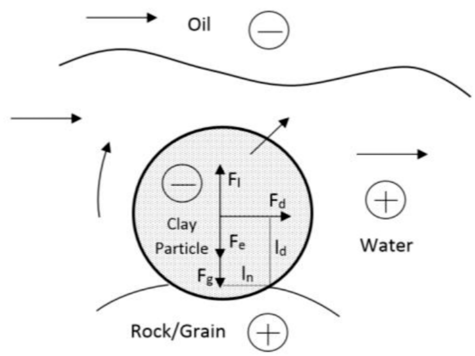


Figure 1—Forces acting on a fine submerged in water

A fine particle on the rock surface/internal cake surface is subject to drag (F_d), lifting (F_l), electrostatic (F_e) and gravity forces (F_g) (Fig. 1). Before the particle is lifted by the drag force, it rotates about the contact point with the sand grain. Hence, the mechanical equilibrium of fine particles on the surface within the pore space is described by the balance of moments of the above forces [1], [2], [3].

Concentration of the particles attached to the surface is a steadily decreasing function of the relationship between detaching and attaching moments, which are defined as the erosion number, ε [4]:

$$\sigma_a = \sigma_{cr}(\varepsilon), \varepsilon = \frac{(l_d / l_n) F_d(U) + F_l(U)}{F_e + F_g} \tag{1}$$

where l_d and l_n are the arms of the drag and normal forces, respectively.

Decrease of water salinity at a constant rate results in reduction of the electrostatic force because clays act as a cation exchanger and the disturbance of moment balance causes the detachment of the upper layer of the attached particles. For this reason, the attached particle concentration is a function of water salinity. Eq. (1) includes both flow velocity and brine salinity dependencies vs. the attached particles concentration [4], [5]. So, clay particles can be detached by increase in flow velocity and/or decrease in brine salinity. The detached particles migrate in porous medium until they are trapped in smaller pores resulting in permeability decline. The corresponding permeability damage function can be obtained by keeping two terms of Taylor's expansion of the reciprocal to permeability [6], [7], [8], which is given by

$$k_{rw-LS} = \frac{k_{rw-HS}}{1 + k_w \cdot \beta \cdot \sigma_s} \tag{2}$$

$$k_w = k_{rwor} \cdot \left(\frac{s_w - s_{wi}}{1 - s_{wi} - s_{or}} \right)^{n_A} \quad (3)$$

where σ_s is the concentration of strained fines, k is the permeability, and βis the formation damage coefficient.

During displacement of oil by low-salinity water, the detached particles are transported by water and block pore throats in flushed zones. Particle straining results in decrease of effective water permeability. This has the potential to control water mobility, increasing sweep efficiency of waterflood at the reservoir scale and thereby improving oil recovery in comparison to a high-salinity waterflood that does not induce fines migration [4].

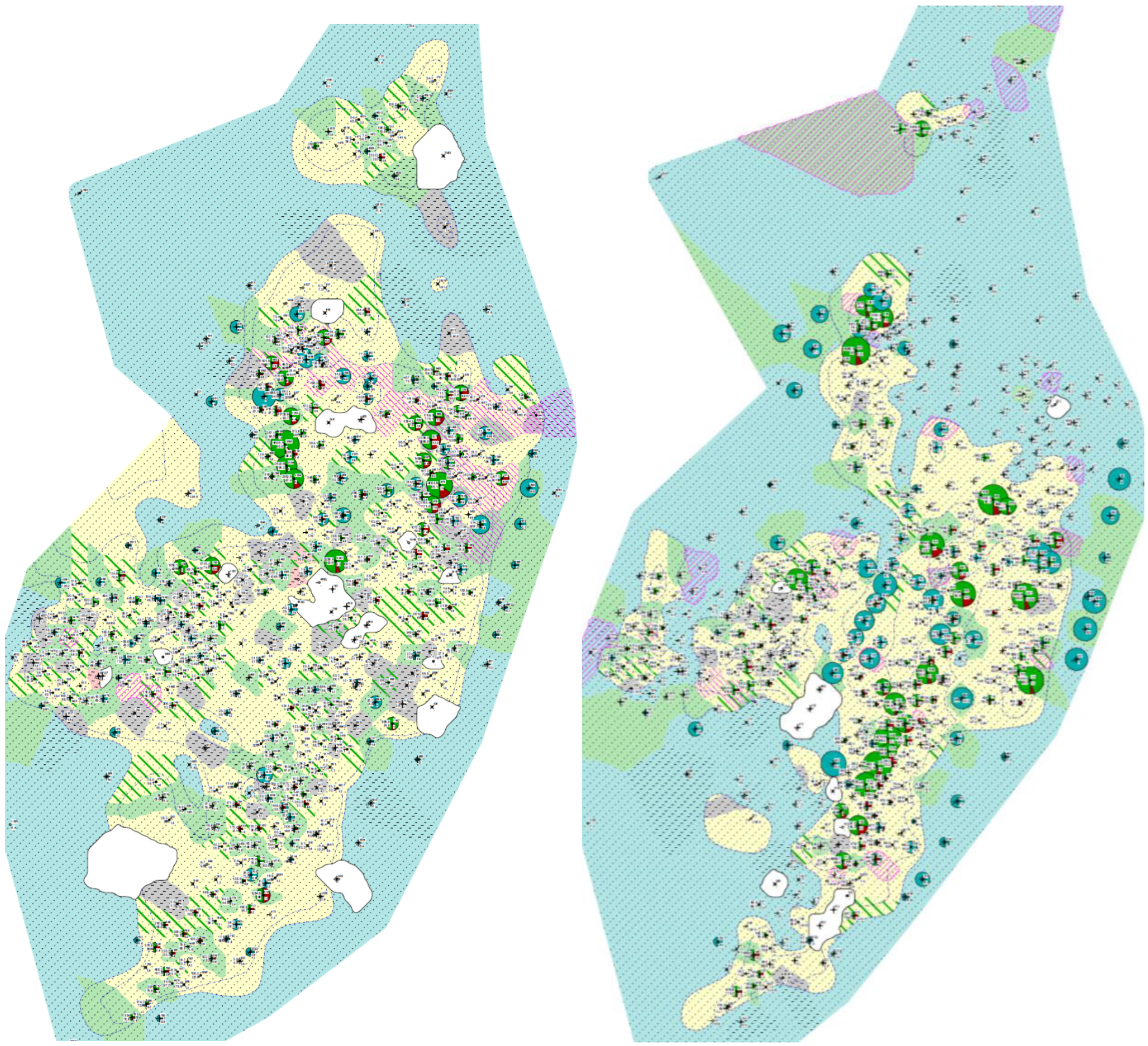
Characteristic of the Pervomaiskoye field and waterflooding system used to displace oil from the Kynovskian-Pashiyskian reservoirs

In the Pervomaiskoye field oil is produced from the Kynovskian-Pashiyskian (99.9% of OOIP) and the Elkhovskian (0.1%) formations. Characteristics of the productive formations are shown in Table 1.

Table 1—Characteristic of the Kynovskian-Pashiyskian formations of the Pervomaiskoye field

Parameter	Value
Average reservoir top depth, m	1650
Water-oil contact, m	-1470
Average formation thickness, m	29
Average effective oil saturation thickness, m	7.5
Average effective water saturation thickness, m	7.6
Average porosity, %	20
Average permeability, md	723
Initial water saturation	0.17
Residual oil-saturation	0.31
Initial reservoir temperature, °C	36
Initial reservoir pressure, MPa	17.2
In-situ oil viscosity, mPa*s	8.2
In-situ oil density, g/cm^3	0.857
Oil density at surface conditions, g/cm^3	0.885
Formation volume factor	1.105
Bubble point pressure, MPa	6.5
Gas-oil ratio, m^3/ton	28
In-situ water viscosity, mPa*s	1.79
Water density at surface conditions, g/cm^3	1.170

The field development began in 1959. Nowadays it has entered the fourth stage of the development. Maximum oil production was reached in 1976. As of January 1, 2015, 187 wells were under production and 127 wells were under injection. All in all, 516 wells have been drilled. Layout of wells is shown on the cumulative production and injection maps (Fig. 2). Accumulated oil production is 49 300 thous. tons, accumulated water production is 209 732 thous. tons, water cut is 90.2 %, current oil recovery factor is 0.482, water-oil ratio is 3.25. Cumulative annual oil production in 2014 was 352.4 thous. tons, water production was 3552.6 thous. tons. The average oil production rate was 5.9 ton/day, water production rate was 60.1 ton/day.



a) Kynovskian formation b) Pashiyskian formation

Figure 2—Cumulative production and injection for the Kynovskian and Pashiyskian formations of the Pervomaiskoye field

As of January 1, 2015, total injected water is 224 904.2 thous.m^3, including 919 85.8 thous. m^3 (40.9 %) of low-salinity water. In 2014, 3671.8 thous. m^3 of water was injected, cumulative voidage replacement ratio was 110.5 %, the current voidage replacement ratio is 110.8 %.

Analysis of waterflooding shows that out of 206 wells under injection, low-salinity water was injected into 71 wells, high-salinity water (98.9 % of produced and 1.1 % of formation water) was injected into 45 wells, both low- and high-salinity water was injected into 90 wells. Almost in all of these latter 90 wells during the first 5-15 years of operation low-salinity water was injected followed by injection of produced water later on. Beyond the oil water boundary (aquifer) or at distance of more than 2 km to the nearest production wells there are 62 wells in which low-salinity water is injected. As was discussed in earlier papers [9], [10], it is deemed that LSW in aquifer zone does not contribute to incremental oil production.

For the purpose of assessment of incremental oil recovery areas subject to low-salinity followed by high-salinity waterflooding are of the most interest. Seven such areas were identified in the Pervomaiskoye field. First, produced high-salinity water was injected in wells for more than 20-25 years, then, beginning from 2005, low-salinity water was used for injection. Each injection well in the pilot area has 2-5 responding production wells that have been in operation since 1970s. For the purpose of the analysis, the impact of all other injection wells was excluded [11]. Figure 3 shows oil recovery factor vs. pore volume injected for each of seven pilots. High-salinity and low-salinity waterflooding are represented by red and blue curves, respectively. Figure 4 shows historical performance of production and injection wells in seven pilot areas.

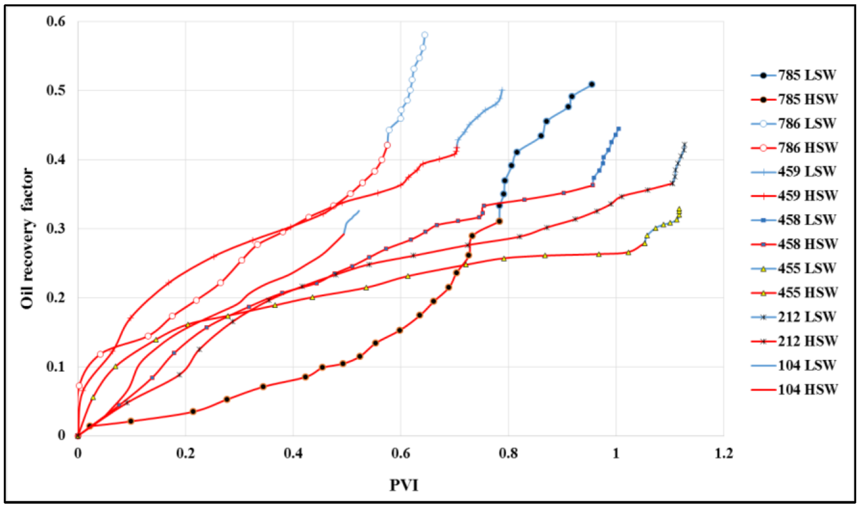


Figure 3—Oil recovery factor for 7 LSW pilots vs. injected pore volumes. HSW (red curves) followed by LSW (blue curves) [11]

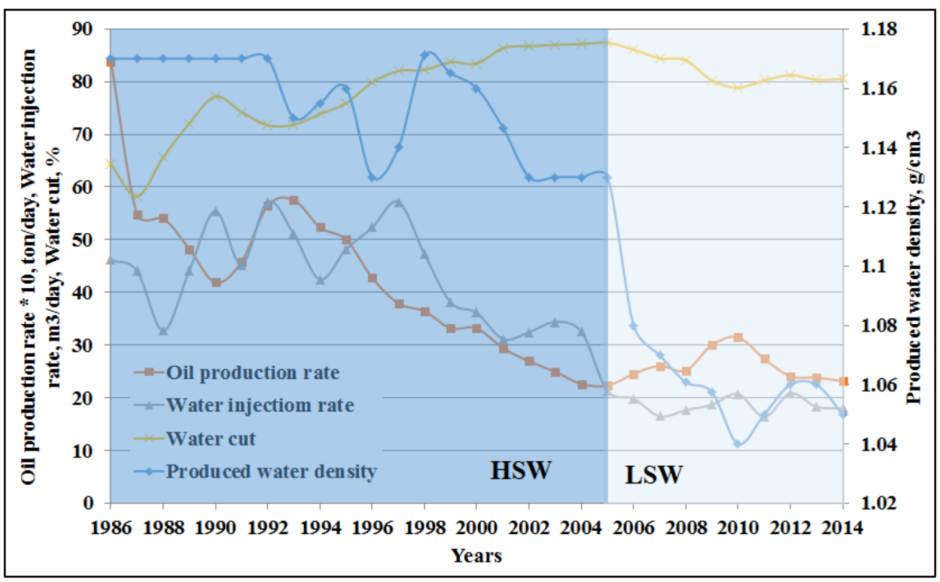


Figure 4—Average performance of production and injection wells over 28 years in 7 LSW pilots [11]

The analysis showed that almost in all pilot areas recovery factor increased after low-salinity water injection (Fig. 3). Partially, it is explained by lower well intake capacity to low-salinity water (Fig. 4). However, low-salinity waterflooding resulted in water cut decrease from 87 % to 80 %, and oil production rate increase from 2.1 ton/day to 2.5-3.1 ton/day confirming, thus, the efficiency of low-salinity waterflooding. Moreover, reduction of density of the produced water from 1.13-1.17 g/cm^{3}to 1.04-1.08 g/cm^3 demonstrates that low-salinity water has reached the producers.

If we extrapolate the oil production curve (Fig. 3) immediately once high-salinity water has been injected, i.e. if injection of high-salinity water continued, oil production rates would be about 1.5 ton/day. Extrapolation of oil recovery factor curves (shown in red) up to current PVI values shows that incremental of recovery in these pilot areas is around 5-9 % by now.

Results of laboratory modeling and calculation of relative permeabilities

Core from the Devonian Kynovskian and Pashiyskian formations were taken from several vertical wells from the depths 1653-1679 m. From full-size cores ten core plugs were cut with diameters 3.9-3.93 cm and lengths 6.51-8.12 cm. The measured porosity and absolute permeability were 17.1-20.4 % and 291-539 md, respectively [12]. The data are summarized in Table 2.

Table 2—Core characteristics

No. of core plug	Diameter, cm	Length, cm	Porosity, %	Permeability, md
1	3.92	6.97	18.5	325
2	3.92	7.55	17.1	368
3	3.93	6.84	17.6	291
4	3.90	6.51	17.9	355
5	3.90	8.02	20.1	421
6	3.92	7.89	19.5	432
7	3.90	8.12	19.7	390
8	3.91	7.91	18.3	328
9	3.92	6.77	20.4	539
10	3.93	7.36	18.9	483

The analysis of cores lithology has shown that they are made of sandstone (60-70 %, on average), siltstone (30-38 %), and clay minerals, mainly, kaolinite (up to 2 %).

In the experiments two types of water were used: artificial water based on the known ionic composition of the formation water (high-salinity) and water from the Kama river (low-salinity). With a knowledge of ionic composition of water and use of the material balance approach molecular compositions of high-salinity and low-salinity water were recalculated. The results are presented in Table 3. In order to keep the original pH of high-salinity and low-salinity water, no NaOH or HCl were added to the prepared solutions.

Table 3—Salt composition of artificial high-salinity water and low-salinity water used for waterflooding in the Pervomaiskoye field

Salt	Molecular weight, g/mol	Concentration, g/l	
		brine water	low-salinity water
NaCl	58.439	124.7176	0.0201
$MgCl_2$	95.205	28.7043	0.0281
$MgSO_4$	120.367	0.0855	0.1378
$CaCl_2$	110.978	99.2310	0.2769
$NaHCO_3$	84.006	-	0.3855
Total		**252.7383**	**0.8484**

Total dissolved solids (TDS), ionic force, density, pH, and conductivity were 252.738 ppm, 4.790 mol/l, 1130 kg/m^3, 6.5, and 51.1 mS/cm, respectively, for high-salinity water and 0.848 ppm, 0.0179 mol/l, 1005 kg/m^3, 7.5, and 1.027 mS/cm, respectively, for low-salinity water.

Dead oil with average viscosity 37.5 mPa·s depending on the temperature was used for the test. Average density of the oil was 826.8 kg/m^3 [11].

After cutting core plugs from the 10-cm full-size core a few 0.5-1.5-cm pieces were left. These were used for core flood experiments involving step change of salinity–from high to low. The samples were only saturated with formation water with no oil. Water at the outlet was collected and analyzed by a particle counter, so, the amount of fines in each sample was recorded.

Figure 5 shows how absolute permeability of the core samples changes depending on the salinity of the injected water.

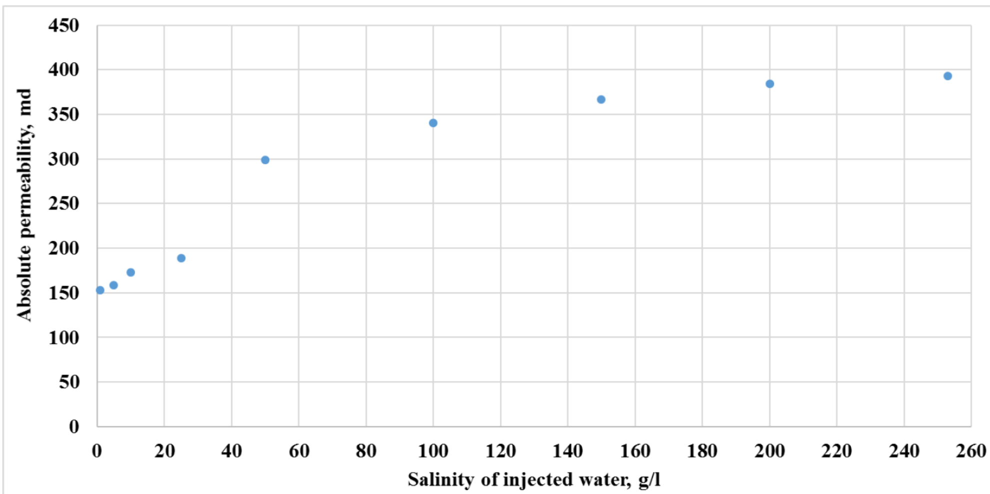


Figure 5—Absolute permeability vs. salinity of injected water

The tests demonstrated that decrease of salinity of injected water from formation to about 1 g/l resulted in 2.6-fold reduction of permeability.

Figure 6 presents pressure drop vs. pore volume injected (PVI) during high-salinity (a) and low-salinity (b) waterflooding for core sample No. 4. It is evident that during high-salinity water injection differential pressure decreases, while during low-salinity water injection it starts to increase once pore volume has been injected. This increase suggests appearance of resistance in the core because of clay fines migration and plugging pore throats. Similar curves have been obtained for the rest nine core plugs.

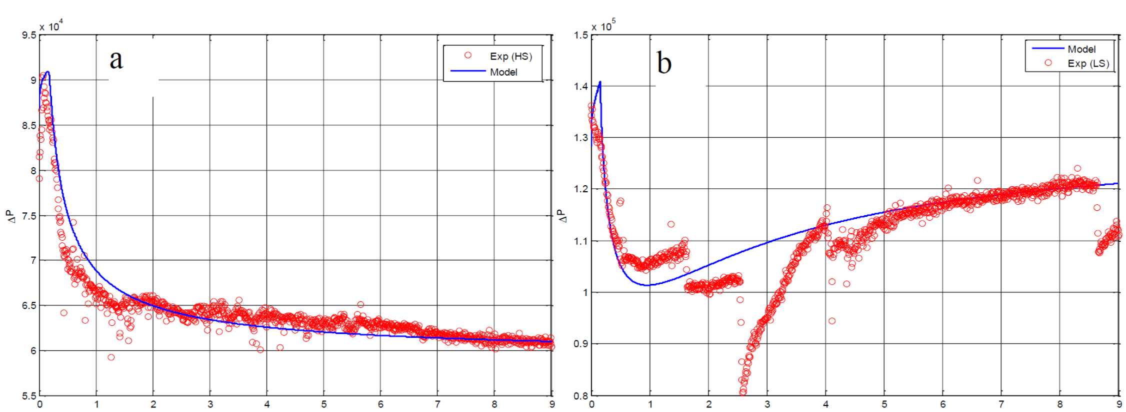


Figure 6—Pressure drop vs. pore volumes injected (sample No. 4) (a) high-salinity water, (b) low-salinity water

Pressure drop for HSW was matched using the numerical model for two-phase flow using the Rappaport-Leas equation; for LSW it was matched using the numerical model for mobilization and migration of fines [12], [13]. As a result, relative permeabilities based on the known Corey equation were estimated (Table 4).

Table 4—Parameters of Corey relative permeability based on results of core flood tests

Core plug	Type of injected water	Initial water saturation	Residual oil saturation	Oil relative permeability at initial water saturation	Water relative permeability at residual oil saturation	Corey exponent for oil	Corey exponent for water
		S_{wi}	S_{or}	k_{rowi}	k_{rwor}	n_o	n_w
No. 1	HSW	0.201	0.325	0.99	0.103	2.2	1.3
	LSW	0.201	0.322	0.99	0.061	2.2	2.5
No. 2	HSW	0.146	0.274	0.99	0.089	2.0	1.8
	LSW	0.144	0.270	0.99	0.024	2.0	3.0
No. 3	HSW	0.235	0.286	0.97	0.119	2.0	1.4
	LSW	0.235	0.285	0.98	0.061	2.0	2.2
No. 4	HSW	0.083	0.580	1.00	0.062	2.5	1.2
	LSW	0.080	0.564	1.00	0.024	2.5	2.7
No. 5	HSW	0.152	0.341	0.99	0.051	2.1	1.1
	LSW	0.150	0.314	0.99	0.019	2.1	2.6
No. 6	HSW	0.126	0.236	0.95	0.078	1.8	1.5
	LSW	0.126	0.235	0.96	0.020	1.8	2.3
No. 7	HSW	0.098	0.469	0.98	0.087	2.0	1.4
	LSW	0.097	0.463	0.98	0.040	2.0	1.9
No. 8	HSW	0.188	0.195	0.96	0.071	2.2	1.8
	LSW	0.188	0.194	0.97	0.015	2.2	3.2
No. 9	HSW	0.269	0.260	0.95	0.065	2.8	1.6
	LSW	0.265	0.234	0.95	0.021	2.8	2.5
No. 10	HSW	0.224	0.206	1.00	0.111	2.3	1.1
	LSW	0.223	0.205	1.00	0,042	2.3	2.1
Average	**HSW**	**0.172**	**0.317**	**0.98**	**0.084**	**2.2**	**1.4**
	LSW	**0.171**	**0.309**	**0.98**	**0.032**	**2.2**	**2.5**

Figure 7 shows the fines release from core sample No. 4 during flooding with high-salinity and low-salinity water. Similar concentrations of fines release from the cores were observed for the rest 9 plugs. Average concentration of fines measured in bottles with liquid after injection of high-salinity water did not exceed 0.005 g/l for all samples, but after injection of low-salinity water it was 0.02 g/l.

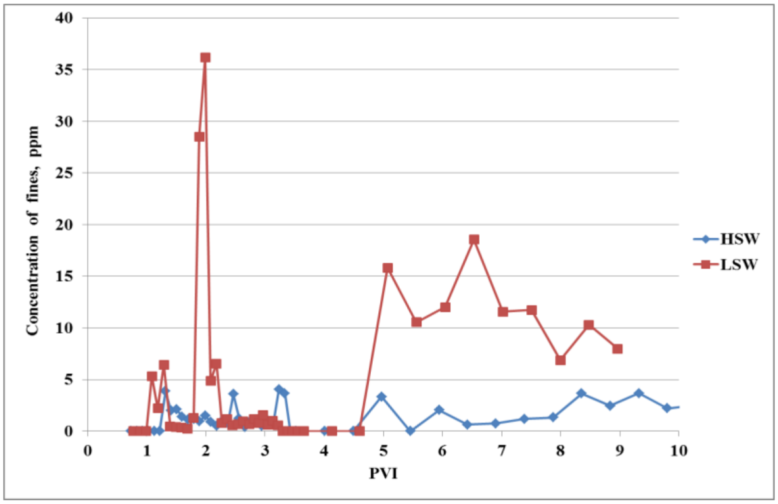


Figure 7—Fines release in core flood experiments using high-salinity and low-salinity water (sample No. 4)

Figure 8 shows relative permeabilities to oil and water for one of the cores (core sample No. 4) during waterflooding with high-salinity and low-salinity water. At LSW, permeability to water starts to decrease as soon as water saturation has reached 0.4. Similar phenomenon was recorded for all tested samples. Explanation of the mechanisms responsible for this phenomenon has been attempted in the earlier paper [14]. The higher water saturation, i.e. the concentration of injected low-salinity water, the greater amount of fines starts moving. As a result, increasing number of the pore throats are blocked, and permeability to water starts to decrease [12].

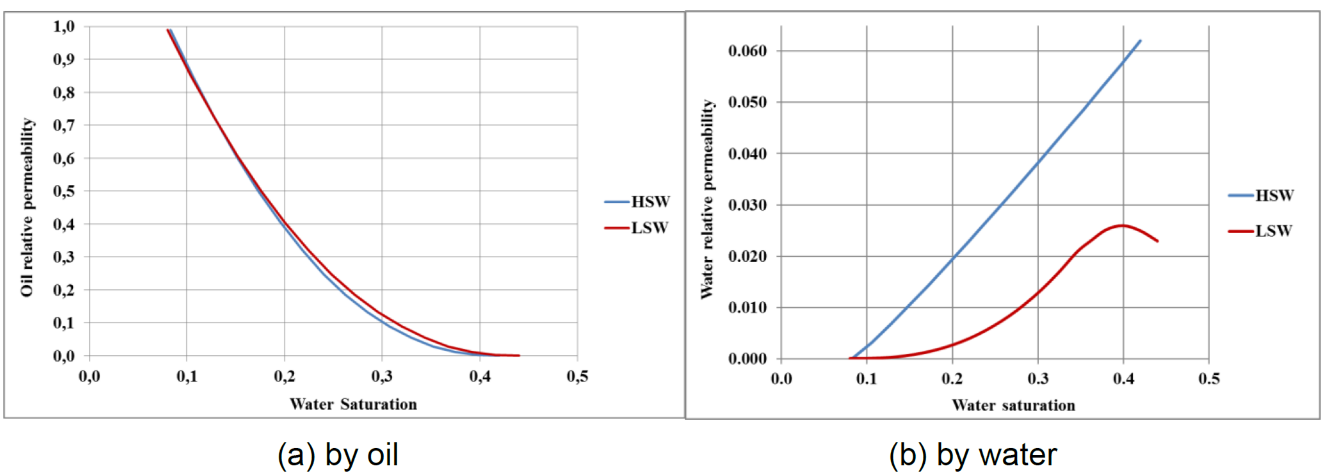


Figure 8—Relative permeabilities to oil and water in HSW and LSW (sample No.4)

From Table 4 one can see that residual oil-saturation during low-salinity waterflooding decreased insignificantly, relative permeability to oil did not change, relative permeability to water decreased 2.6-fold [12]. The main reason behind this is presence of clay fines in the rock. The action of low-salinity water leads to decrease of electrostatic forces, which hold the particles, detachment of these particles from rock surface, their migration and blocking pore throats. Absolute permeability to water, thus, decreases in flushed zones while in oil-saturated zones it remains unchanged, because less injected water gets there. Relative permeability to water decreases. Small decrease of residual oil saturation is due to wettability alteration of those rock areas, which originally were mostly oil-wet.

3D reservoir model of the field

First, using well data available as of January 1, 2015, 3D geological model was built using RMS software product. According to the model, OOIP was 120 801 thous. m^3, which is 0.4 % higher than volumetric estimates of oil in-place. Then, the geological model was uploaded to the 3D reservoir simulator Tempest More. Reservoir characteristics, which were used to create the model, are shown in Table 1. The general view of the reservoir model is shown in Fig. 9. Figure 10 shows distribution of initial oil saturation, Fig. 11–vertical slices along I-I and II-II lines, representing distribution of permeability.

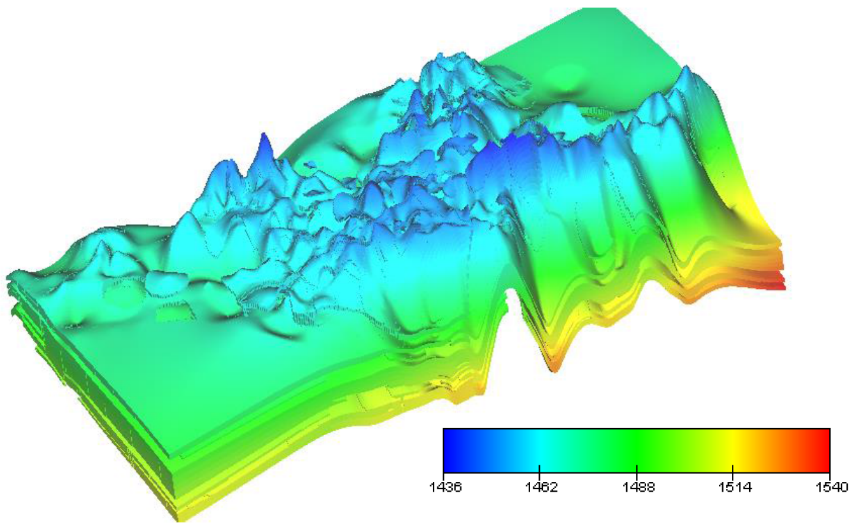


Figure 9—General view of 3D reservoir model (depth distribution)

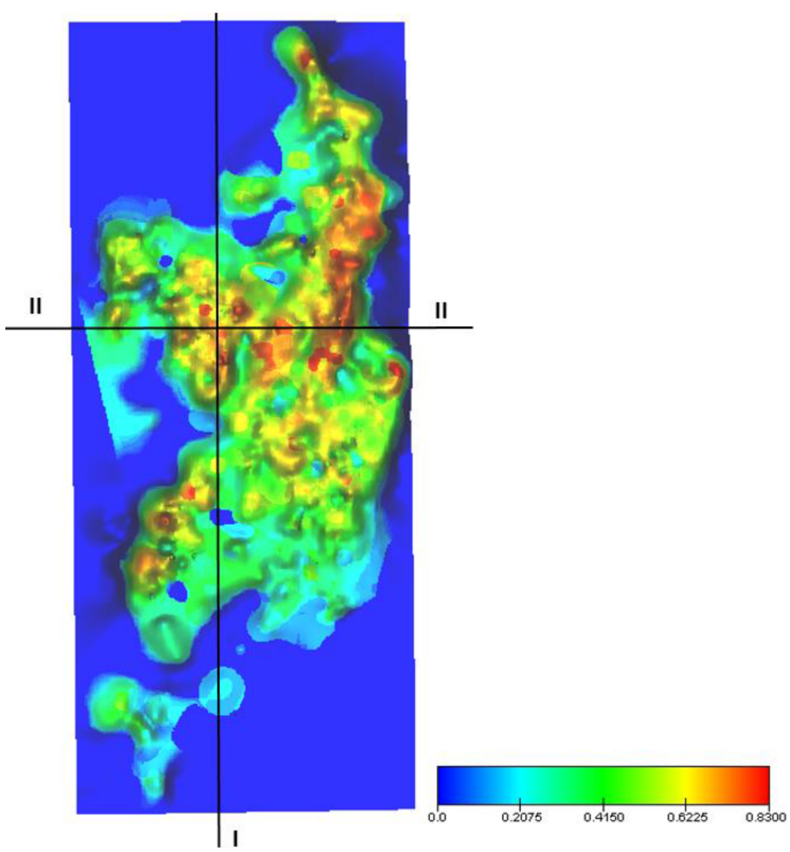


Figure 10—Map of initial oil saturation distribution

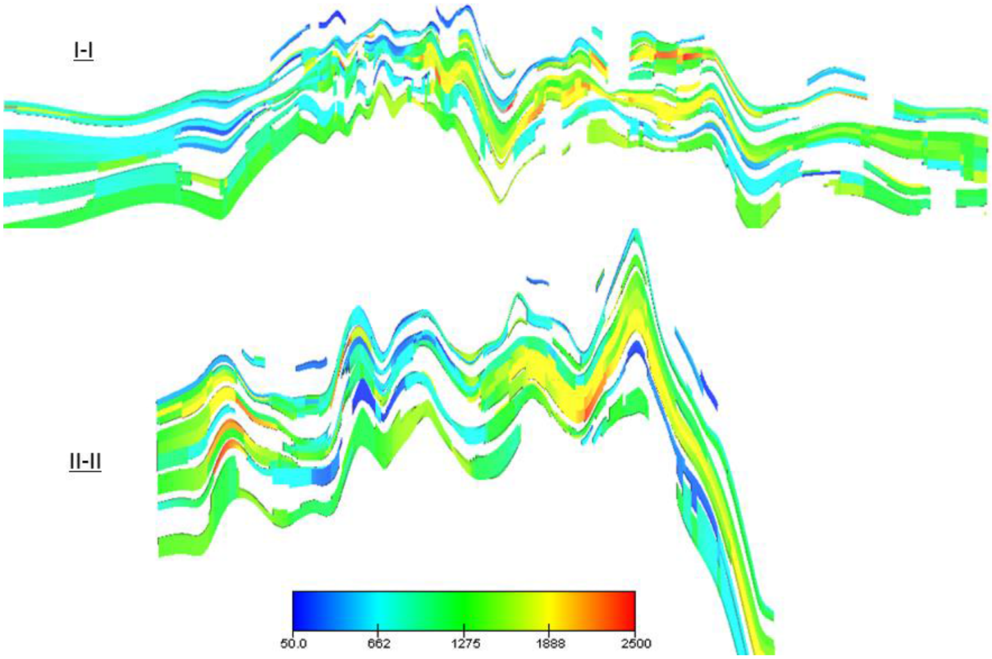


Figure 11—Vertical slices along I-I and II-II lines–permeability distribution

To model LSW, the Tracer function was used, which allows to choose properties of the injected water that are able to change relative permeability and/or saturation depending on concentration of water in reservoir.

The laboratory tests data were recalculated to obtain a factor of relative permeability to water vs. concentration of injected low-salinity water in reservoir (Fig. 12). One can see that at maximum concentration of low-salinity water in reservoir (1.0) relative permeability to water is reduced 2.6-fold, i.e. the factor is 0.39.

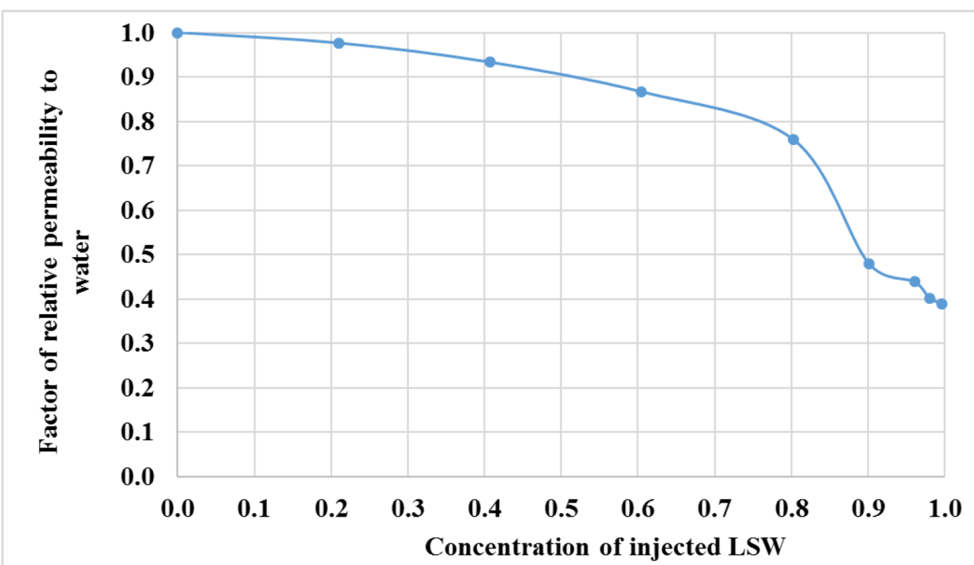


Figure 12—Factor of relative permeability to water vs. concentration of injected low-salinity water in reservoir (Tracer option)

Results of 3D reservoir simulation

As a result of history matching of the 3D reservoir model based on injection of low-salinity and high-salinity water, Corey curves of relative permeabilities were obtained (Fig. 13, Table 5). The Kynovskian and

Pashiyskian formations were considered as a single target, because, first, the relative permeability curves are similar for both formations, and, second, not infrequently these formations converge.

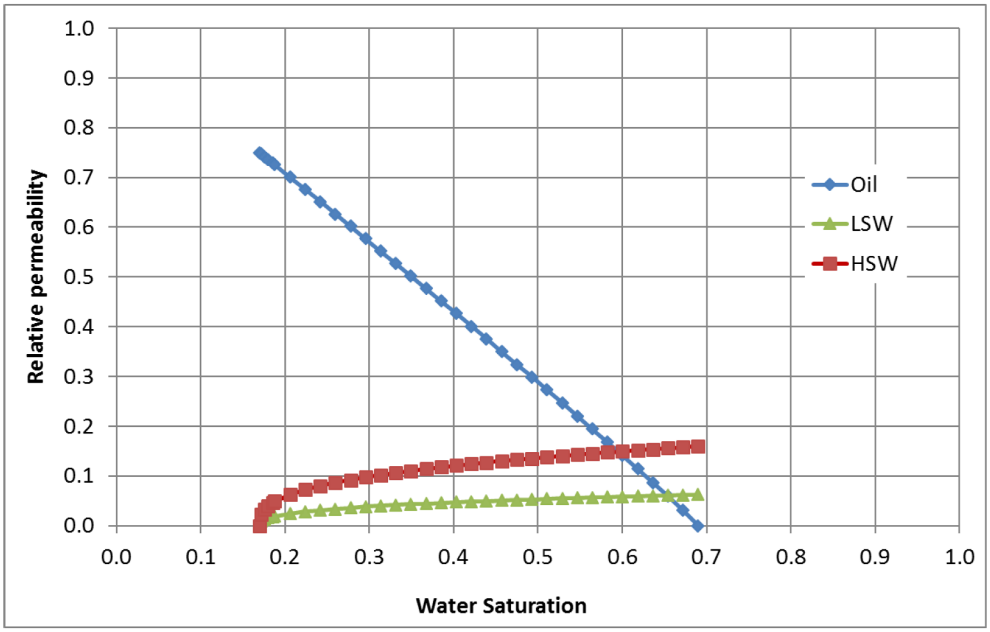


Figure 13—History-matched dependencies of relative permeabilities

Table 5—Corey exponents for the Kynovskian-Pashiyskian formations of the Pervomaiskoye field by the results of reservoir model history matching

Parameter	Symbol	HSW	LSW
Initial water saturation	S_{wi}	0.17	0.17
Residual oil saturation	S_{or}	0.31	0.31
Oil relative permeability at initial water saturation	K_{rowi}	0.75	0.75
Water relative permeability at residual oil saturation	K_{rwor}	0.160	0.062
Corey exponent for water	N_w	0.35	0.35
Corey exponent for oil	N_o	0.95	0.95

Figures 14 and 15 present maps of distribution of injected low-salinity water concentration (Tracer function) and distribution of oil saturation as of January 1, 2015. Figure 16 presents history-matched curves of reservoir performance under LSW; all values are shown under reservoir conditions.

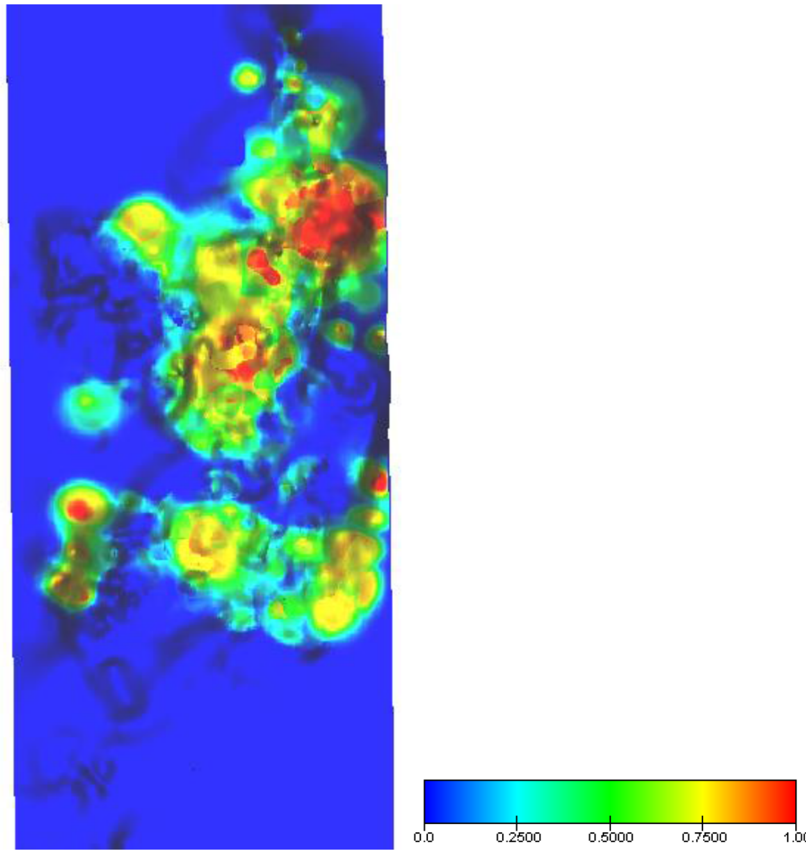


Figure 14—Distribution of concentration of injected low-salinity water as of January 1, 2015

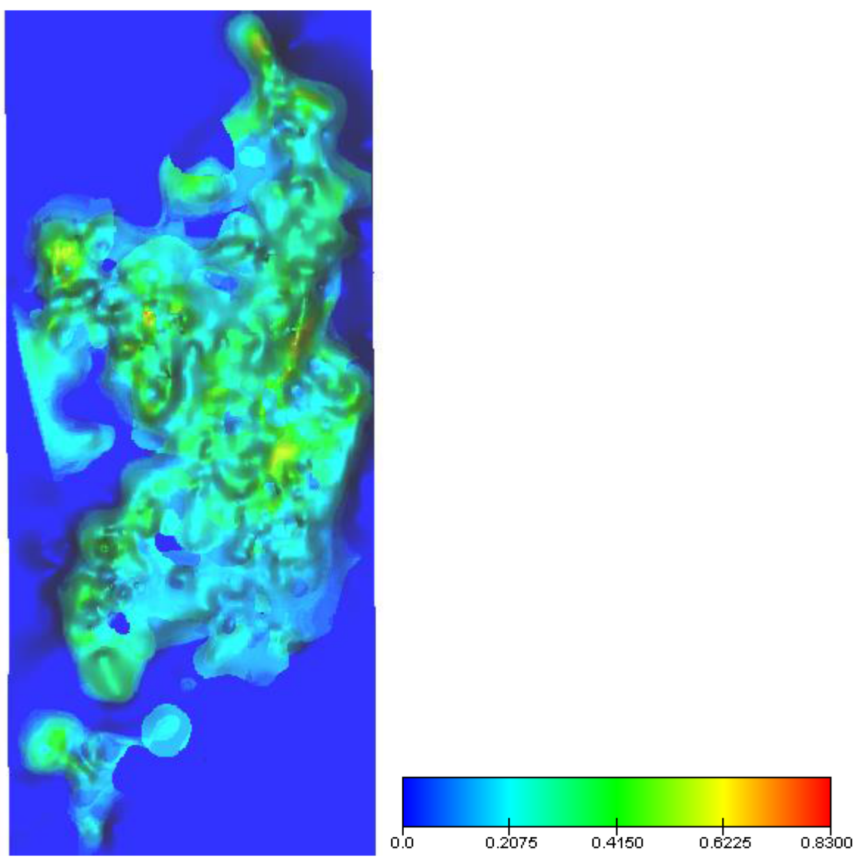


Figure 15—Distribution of oil saturation as of January 1, 2015

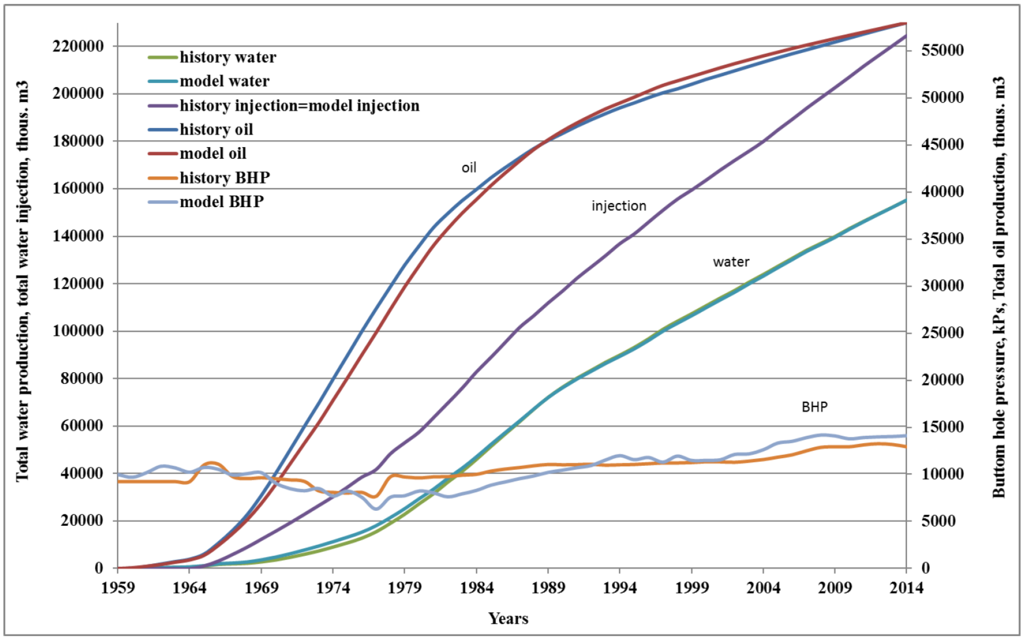


Figure 16—History-matched LSW model of the Kynovskian-Pashiyskian formations of the Pervomaiskoye field

Correlation coefficient for annual oil production is 0.98-0.99, for average bottom hole pressure of production wells–0.89. Cumulative oil production by the model is 58 003.6 thous.m^3, which practically coincides with the actual production, 57 999.6 thous. m^3. Water production and injection have been matched with 100 % accuracy, oil recovery factor by the model is 0.480, differing from the actual figure by mere 0.002. The 3D LSW model was, thus, history matched with a sufficient degree of accuracy both in terms of production and injection and bottom hole pressure.

To estimate incremental oil production, the model was recalculated from the beginning of development without the Tracer function, i.e. without changing of relative permeability to water, which corresponds to injection of high-salinity water. The results of calculation in comparison to low-salinity waterflooding are shown in Fig. 17. Positive results of injection of low-salinity water:

- Incremental oil production from the beginning of development made 4188.3 thous. m^3 or 7.2 % of the cumulative oil production;
- Cumulative water production was less by 12 408.3 thous. m^3 or 8 %;
- Incremental oil recovery factor made 3.5 % [12].

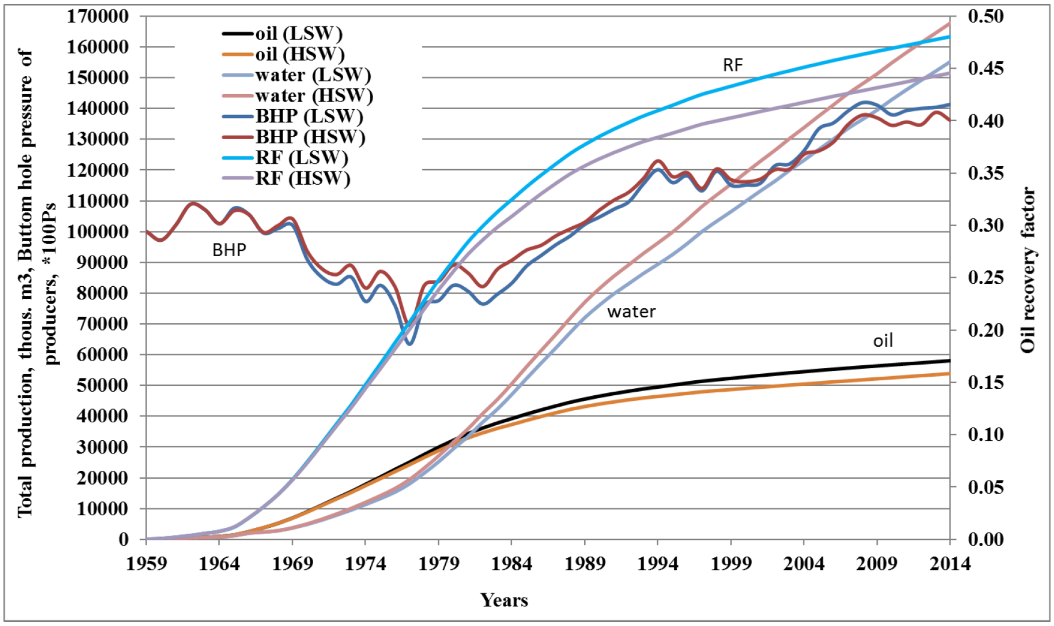


Figure 17—Production performance under LSW and HSW

Analysis of incremental oil production due to LSW shows that the effect was observed in wells with wellstream water cut from 20 % to 90 % (Fig. 18).

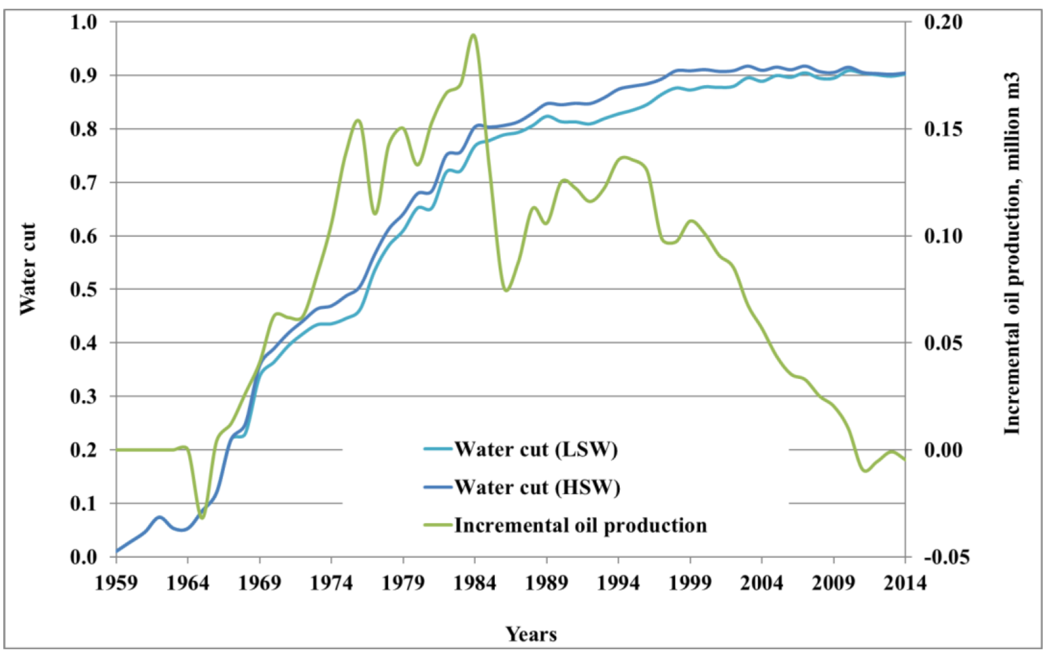


Figure 18—Incremental oil production and water cut for low-salinity waterflood (LSW) and high-salinity waterflood (HSW)

Discussion

Plugging of pore throats by migrating fines decreases absolute permeability of reservoir. As far as injected water tends to go to the swept zones first, these zones are blocked by the fines, while the oil saturated part of the reservoir remains unaffected. Relative permeability to water decreases, while relative permeability to oil remains the same. Water injected afterwards bypasses the blocked zones resulting eventually in increase of sweep efficiency and oil recovery, and, to some extent, works also as a water control technology. Considering that by the results of core flood tests the residual oil saturation of cores practically did not change for both high- and low-salinity waterfloods, the ultimate oil recovery at sweep efficiency being equal to unity (1) did not change either. However, in real conditions the sweep efficiency is much lower than 1, so the effect of increase of oil recovery due to LSW and fines migration consists in increase of sweep efficiency, which, in its turn, depends on the phase mobility ratio. For the Pervomaiskoye field, water vs. oil mobility is 4.6 times higher with high-salinity water and 3.2 times higher with low-salinity water.

Why no effect was observed in wells with water cut of the wellstream beyond the abovementioned range (20–90 %)? We can offer the following explanation. In the initial period of development with low water cut of the production there are no swept zones yet. Permeability of oil saturated reservoir decreases, so the effect might be negative. With high water cut cumulative effect is reduced to zero. Flood displacement efficiency during injection of low-salinity water does not change, and at high values of oil recovery and, accordingly, sweep efficiency tending to unity the same amount of oil will be produced. That is why, the current recovery only increases, but not the ultimate recovery.

Conclusions

Summing up the results of our research we can say that both injection and production wells may benefit from low-salinity water injection, however only targeted LSW can be recommended for the Kynovskian-Pashiyskian formations of the Pervomaiskoye field. In injection wells it holds the potential for enhancing oil production but only in case water cut of the wellstream is in the range from 20 % to 90 %; in production wells LSW can be effectively used to control water production.

References

1. Bradford, S., Torkzaban, S., Simunek, J., 2011. Modeling colloid transport and retention in saturated porous media under unfavorable attachment conditions. *Water Resour. Res.* **47** (10), W10503.
2. Freitas, A., Sharma, M., 2001. Detachment of particles from surfaces: an Afm study. *J. Colloid InterfaceSci*. **233** (1), 73–82.
3. Zinati, F., Farajzadeh, R., Currie, P., Zitha, P., 2009. Modeling of external filter cake build-up in radial geometry. *Pet.Sci.Technol.* **27** (7), 746–763.
4. Hussain F., Zeinijahromi A., Bedrikovetsky P., Badalyan A., Carageorgos T., CinarAn Y., 2013. Experimental study of improved oil recovery through fines-assisted waterflooding. *Journal of Petroleum Science and Engineering*.
5. Bedrikovetsky, P., Siqueira, F., Furtado, C., Souza, A., 2011. Modified particle detachment model for colloidal transport in porous media. *Transp. Porous Media* **86** (2), 353–383.
6. Al-Abduwani, F., Farajzadeh, R., van den Broek, W., Currie, P., Zitha, P., 2005. Filtration of micron-sized particles in granular media revealed by X-Ray computed tomography. *Rev. Sci. Instrum.* **76** (10) (103704-1–103704-6).
7. Civan, F., 2007. *Reservoir Formation Damage: Fundamentals, Modeling, Assessment, and Mitigation*. Gulf Professional Publishing, Elsevier, Burlington.
8. Pang, S., Sharma, M., 1997. A model for predicting injectivity decline in water-injection wells. *SPE Form.Eval.* **12** (3), 194–201.
9. Case Study of Low Salinity Water Injection in Zichebashskoe Field / A. Zeinijahromi, V. Ahmetgareev, A. Badalyan, R. Khisamov, P. Bedrikovetsky // *Journal of Petroleum Science Research*. - 2015. - V. **4**, Issue 1. - P. 16–31.
10. Sensitivity study of low salinity water injection in Zichebashskoe Oilfield / A. Zeinijahromi, V. Ahmetgareev, R. Ibatullin, P. Bedrikovetsky // *Journal of Petroleum and Gas Engineering*. - 2015. -V. **6** (1). - P. 10–21.

11. Akhmetgareev, V. 40 Years of Low-Salinity Waterflooding in Pervomaiskoye Field, Russia: incremental oil / V. Akhmetgareev, R. Khisamov // Paper SPE-174182 presented at the 11th SPE European Formation Damage conference held in Budapest, Hungary, 3-5 June.
12. Akhmetgareev, V. 2016. Results of Laboratory Modeling of Low-Salinity Waterflooding of Sandstone and Carbonate Reservoirs in Tatarstan // *Oil Industry Journal*. Vol. **6**. - P. 90–93.
13. Lemon, P. Effects of Injected-Water Salinity on Waterflood Sweep Efficiency Through Induced Fines Migration / P. Lemon, A. Zeinijahromi, P. Bedrikovetsky // Paper SPE-140141 presented at SPE International Symposium on Oilfield Chemistry held in The Woodlands, Texas, USA, 11-13 April 2011.
14. Zeinijahromi, A. Effects of induced fines migration on water cut during waterflooding / A. Zeinijahromi, P. Lemon, P. Bedrikovetsky // *Journal of Petroleum Science and Engineering*. - 2011. - **78**. - P. 609–617.
15. Experimental study of improved oil recovery through fines-assisted waterflooding / F. Hussain, A. Zeinijahromi, P. Bedrikovetsky, A. Badalyan, T. Carageorgos, Y. CinarAn // *Journal of Petroleum Science and Engineering*. - 2013.